KX 9

Alta Mesa Resources Roadshow – Potential Investor Questions

A. General

1. What is medium to long-term roadmap for the combined company? Focused on developing existing acreage or will you be a basin consolidator (or both and which will you emphasize and how)?
    a. Short term focus is developing identified 4,196 locations in Osage, Meramec and Oswego, but outlook is for continuation of both developing additional benches and seeking opportunistic acquisitions
    b. Access to public capital will allow us to be a natural consolidator
    c. With significant technical resources, we believe we can push the basin limits both horizontally and vertically
2. What does offset operator activity look like in the target vs upside zones? Why does Alta Mesa focus on the Osage primarily when other STACK operators seem to be focusing primary on the Meramec and Oswego?
    a. Although offset operators predominantly target the Meramec, several are beginning to recognize the viability of the Osage; significant offset activity is also targeting the Oswego (Chesapeake)
    b. On much of our acreage, both the Meramec and Oswego are proven productive by old vertical wells, so we began successful testing/development of the Osage
    c. We have a distinct advantage of significant natural fracturing throughout the Meramec/Osage section that is not enjoyed by operators in the pressured area of the play
    d. We drilled our first horizontal Manning test and it is currently being completed
3. Can you discuss how you differ from one-bench plays like the Eagle Ford and Bakken – will you be in this category or should I think of you as a multi-stacked pay zone company like Permian comparables?
    a. Alta Mesa has stacked-pay potential very similar to the Permian. When we refer to the STACK internally, we mean the 1,100' oil-saturated section from the Big Lime through the Hunton. Prospectivity is high for all existing and potential target zones. Alta Mesa and others have already drilled successful Oswego, Meramec, Osage, Woodford, and Hunton horizontal wells. Additional formations, including Big Lime and Red Fork, have horizontal permits and strong vertical production. Extensive and full-scale vertical well history exists across the Alta Mesa target formations.
4. Prospects for bolt-on acreage, prices you are seeing, future plans for M&A. Why will Alta Mesa have a strategic advantage on bolt-on acquisitions versus other STACK operators?
    a. We continue to have a technological completion advantage as demonstrated by successful wells where others have been unsuccessful (NFX JV, Longfellow JV, Chaparral farmout)
    b. We have a large, contiguous acreage position with significant built-for-purpose infrastructure which gives us lower costs for water sourcing/disposal, gas processing/transportation, oil/ngl transportation
5. Does Alta Mesa anticipate being a STACK pure-play operator or are there long-term plans to acquire acreage and expand into other basins? If so, what type of basins would you target?
    a. At this time, our focus is to remain a pure-play operator in the STACK, but we are focused on the Mid-Continent for the long-term given the number of opportunities in the basin (i.e. plenty to do here for our lifetimes). The Mid-Con "provides several lifetimes of opportunities."
    b. Future plans may include expansion/consolidation in the STACK, SCOOP, Merge, and the NW extension of the STACK
6. Please discuss the Major County Acquisition acreage in more detail. How do you feel about the potential success of drilling out this acreage given the limited well results in this area / relatively younger development?

  a. This position is really not much different, from a maturity standpoint, from our current position 4+ years ago
  b. We see good vertical well results in Major County, much like Kingfisher County
  c. This acreage is on trend with our position in Kingfisher County and has similar stratigraphic characteristics in terms of limestone with a high concentration of quartz
  d. Most, if not all, of the limited well results do not use our completion methodologies

7. Tell me about the management incentive structure.
   a. ?
8. Who are your closest peers?
   a. Primary OK: Newfield, Devon, Marathon, Chesapeake, Continental
   b. Secondary OK: Chaparral, Gastar, Cimarex, Longfellow
   c. Also Permian peers for which we share type well IRR, margin, growth and resource life characteristics (Laredo, Matador, Diamondback, RSP Permian, Jagged Peak).
9. How do I compare Alta Mesa with high growth Permian peers with typically higher EURs and IRRs?
   a. See above. Alta Mesa shares very similar characteristics to these high-growth Permian peers and should trade at a multiple similar to these peers.
   b. On almost any per foot or per dollar metric, our mean well result is premiere in the STACK
   c. We compare very favorably to the Permian, especially when lower upfront land prices are included in the economics.
   d. Our focus is on value creation and generating the best economics for each dollar invested
10. How did Silver Run approach acquisition economics for Alta Mesa?
    a. We used both NAV and Public Market Multiples analysis as justification for the price we offered. We also included fully diluted sponsor shares and all SR2 warrants in our analysis.
11. What price assumptions were used when evaluating the Major County Acquisition?
    a. We look at a variety of price metrics: Strip, Consensus, Upside, Downside, $/acre
12. Why this deal in this basin?
    a. Alta Mesa presents an unmatched opportunity to acquire a company with a highly experienced management team (in-basin), robust type-well economics, combined upstream/midstream business (and valuation uplift long-term therefrom), decades of inventory life, and at an early-stage of development. It's a perfect fit with SR2's strategic and economic objectives laid out on the original road show in late March. We have been conducting valuation and technical due diligence for several months and feel confident this is a great first step for SR2.
13. Did Alta Mesa run an auction? Who were your competitors?
    a. Alta Mesa was considering an IPO of the company and received significant valuation feedback (and markers) as part of that process. The price RS II is paying for Alta Mesa is competitive with the regular-way IPO of Alta Mesa potential valuation, thus we feel confident in the terms to which we agreed. In addition, the RS II acquisition will allow Alta Mesa to raise greater proceeds than would be possible in a regular IPO, thus improving liquidity and enhancing Alta Mesa's ability to execute their long-term development program more effectively. In addition, Alta Mesa would not have been able to (insufficient capital to) combine KFM and Alta Mesa as part of a regular IPO, which is a unique advantage that the RS II transaction provides. Good answer.
14. Is Silver Run II paying the IPO value? Was Alta Mesa prepared to go public at this value? Why didn't they?
    a. See above. Alta Mesa was prepared to remain private or go public, but the opportunity to add Jim Hackett as Chairman was an unmatched, highly accretive add to help the organization grow, particularly in the area of making accretive acquisitions. In addition, the

combined business RS II is acquiring has more long-term potential for investors versus an IPO of the upstream-only company. Thanks and I believe it is a valid answer.

15. Where will Riverstone ownership settle over time?
    a. 20%? Current page 10 of presentation. We will hold our approx. 20% for a minimum of the lock-up period, but will be selling portions of our position over time solely to match the needs of our private LPs. AMR is the kind of asset which we like to hold as long as practicable.
16. What well costs did you use in your acquisition economics?
    a. Riverstone utilized the well costs provided in Alta Mesa's roadshow materials and ran sensitives to the downside thereon in the drill-out model to ensure the value being offered was accurate Agree.
17. What's your acreage worth on a per acre basis, fully developed? **[Note: This question was deleted from Citi's document; not sure if that was by design]**
    a. Excluding KFM value, PV10 of identified location drillout plan is $4.9B at NYMEX and $6.5B at Consensus pricing
    b. For 100k acres (excluding NW Expansion), acreage value range is $49k-$65k/acre
18. How will you benchmark yourselves in the public markets (debt adjusted shares, ROCE, etc.)
    a. We expect our primary valuation metrics will be FV / EBITDA and P/NAV. Secondary metrics will be P/CFPS and PDP-Adjusted acreage multiples. Once the market normalizes into a long-term set price environment, we believe debt-adjusted production growth per share will once again become a more prominent evaluation metric for valuing E&P companies. We are also very cognizant that an important measure of sustainability in today's weak commodity environment is Debt/EBITDA and we plan to maintain a strong ratio – as evidence to investors and potential partners of balance sheet strength and execution capability.
19. How long will Mr. Hackett be involved with the enterprise?
    a. Mr. Hackett is committed to Alta Mesa's success and this will be his primary focus for the foreseeable future. Mr. Hackett's role as Chairman will require less time than a CEO position and thus will enable Jim to remain active longer-term with Alta Mesa. He is eager to partner with AMR's excellent leadership team. And, he is confident he can manage his other secondary duties with Riverstone.
20. Why should I own your stock vs. your peers?
    a. Only pure-play STACK player
    b. One of few with midstream advantages
    c. Highly quality long-term professional team with demonstrated success where others have failed
    d. Team has a proven track record of success in private and now public markets in upstream and midstream businesses of scale.
    e. In short, Alta Mesa presents a unique (one-of-a-kind) opportunity to invest in a high-margin, high-growth STACK pure-play company. Investors do not have this exact opportunity set in front of them in the public market place. As a result, Alta Mesa will give investors an opportunity to invest directly in the premier STACK basin and realize direct benefits from Alta Mesa's development and consolidation thereof.

B. Market & Commodity Prices

1. What is the average break-even price for your current inventory? What percentage of your current inventory is economic at current prices?
    a. $22.40/bbl is our break-even based on a 15% discount. 100% of our identified inventory is economic at this price.

2. Is there an oil/gas price that will make you accelerate your program?
    a. Yes, if prices increase and our cash flow grows, we will consider ramping rigs when it maximizes returns to our shareholders. Most of our acreage is HBP, so we have the ability to scale up or down as markets warrant. However, we will remain committed to our long-term leverage and liquidity targets and plan for a price deck below the current market levels (whatever they may be at the time).
    b. Our existing plan is to first concentrate on accelerating our Meramec/Osage/Oswego program
    c. Some additional zones, we believe, are also economic at current prices and could be accelerated
    d. Other additional zones will require various higher prices
3. At what oil/gas price do you stop drilling?
    a. Given our <$25 / bbl break-even price, oil and gas prices would have to drop dramatically for Alta Mesa to need to cease drilling; we do not believe this will occur for an extended period
    b. Stopping all drilling is rarely a good option and our balance sheet should protect from us having to do so, especially for temporary periods.
4. Did you drop rigs when the downturn began? What was the thought process driving your pace of activity during the downturn?
    a. We had one OEH operated rig in 2014, increased to 2 in 2015, and exited 2016 with 5 rigs; we added the sixth rig in January, 2017
    b. We have been successful maintaining, and even increasing, our drilling even during this nearly 3-year downturn. The resulting advantage has been retaining top drilling/frac crews and growing production as prices have risen
    c. One of the smartest things we did at year-end 2014 was to embrace low oil prices as the new reality and build our cost structure around that concept.
    d. We had a good structure in place with the DrillCo
5. How do you think about oil, gas and NGL prices in the next five years?
    a. We see gradual strengthening in prices based on better macro conditions, especially on the liquids side of the business, with opportunities to protect earnings through hedging
6. What commodity price deck do you use to make capital planning decisions?
    a. Typically, NYMEX strip pricing with lower and higher sensitivities
7. How is Kingfisher Midstream ("KFM") impacted by a downturn or upturn in commodity prices (does it have any impact)?
    a. KFM contracts with AMR are fee-based, so there are no immediate impacts from commodity prices
    b. Medium-long term change in prices could impact mostly third party volumes going through the plant

C. Acreage / Drilling Inventory

1. What benches are most prospective in your operating area? How much vertical well history exists in each of those benches?
    a. Prospectivity is high for all existing and potential target zones. Alta Mesa and others have already drilled successful Oswego, Meramec, Osage, Woodford, and Hunton horizontal wells. Additional formations, including Manning, Big Lime and Red Fork, have horizontal permits and strong vertical production. Extensive and full-scale vertical well history exists across the Alta Mesa target formations.
    b. All target zones produce vertically with the exception of the Chester Shale.

2. How do you approach type well IRR calculation? What is included/excluded on the cost side? **[Note: This question was deleted from Citi's document; not sure if that was by design]**
   a. Type well EURs are based on the mean well result of our producing wells
   b. Type wells production forecasts are based on the P50 result of our producing wells
   c. All operating costs, processing fees, drilling, completion, and facility costs are included in the IRR calculation

   Good answer
3. When do you evaluate and start to develop your upside benches (what year)? When does full-scale development of the upside benches begin? This begs the question of the importance of "benches" in the other three primary basins in which we are already drilling.
   a. We have drilled, and are in the process of completing, our first Manning test
   b. We have also drilled successful Woodford and Hunton (upside zone) wells
   c. Limited additional testing will likely be warranted and full-scale development will commence afterwards
   d. We will likely drill additional Hunton and Woodford tests in the near future
   e. Additional horizons will be tested as conditions improve and as they can be worked in to existing development plans
4. Do you anticipate any significant leasehold expirations? What is your plan to minimize acreage loss and hold all your acreage by production?
   a. Post the Major County acquisition, we have about 20,000 acres that could expire in the next 3 years
   b. Approximately +80% of our leasehold is HBP
   c. We can hold all of our acreage with a single rig
5. Are there parts of the STACK you would not buy assets?
   a. At this time, there are no parts of the STACK we would not buy at a certain price
   b. The STACK is an evolving play and the possibilities of acreage status and active horizontal zones across the play will change over time as additional development occurs. In the short-term, Alta Mesa will focus on areas of the STACK that are closer to Alta Mesa's current acreage position geographically and that maintain similar characteristics to Alta Mesa's current STACK acreage position.
   c. Will target liquids rich play-types??
6. How have leasing rates and methods changed in the STACK since your initial entry? Do you see any greenfield leasing opportunities or has all acreage been leased up?
   a. We were fortunate early-on to be a stealthy player in the updip, naturally fractured STACK
   b. In various areas, we have historically seen rates range from $500/acre to $8,000/acre (check this)
   c. Competition is strong, but we see about 2.1 million acres in play from private equity backed companies and about 500k acres from in-play public companies
7. When do the majority of your leases expire?
   a. Majority of Kingfisher County is HBP
   b. Much of Major County acquisition expires over the next 3 years

8. How do you plan to de-risk your Major County Acquisition position? **[Note: This question was deleted from Citi's document; not sure if that was by design]**
   a. Very similar to our de-risking in Kingfisher County
   b. Acquire acreage to maximize interest in early wells (to maintain confidentiality)
   c. Drill pilot hole for detailed reserve/geological information, verify landing point

d. Drill and test; since area is geologically similar, we should have a shorter learning curve

e. Expand acreage position in tandem with drilling/acreage evaluation (while it's "cheap")

9. How should I think about future leasehold capex? **[Note: This question was deleted from Citi's document; not sure if that was by design]**

a. We believe 20k acres in Major can turn into 80k acres

b. In Kingfisher, we spend easily spend about $2MM/month picking up acres in and around our footprint as a normal course of business

c. Large scale acquisitions are a wildcard in terms of size/cost and we fully expect large positions will be available

Cool answer

D. Operations

1. How do you feel about rig availability given your planned rig ramp? From where do you source your rigs? What about pressure pumping?

   a. Rigs are not anticipated as a problem

   b. Most of our rigs are from Latshaw Drilling which has a fleet of 41 rigs

   c. We are also looking to bring on a rig from another driller

2. Do you see any issues with your service providers having access to capable people?

   a. Oklahoma is a primary operating region for US oil and gas E&P operations. As such, we have adequate and constant supply from service providers and access to capable people. Given Alta Mesa's large existing team, we feel confident Alta Mesa has the staff on hand to prosecute the planned large-scale development program

   b. Good capable people are critical which is why we've been fortunate to drill through the downturn

   c. Many of these people know they would have been unemployed without Alta Mesa so the loyalty is strong

   d. As we grow, be believe we and the contractors can add or develop the expertise. . As a larger and larger company in the Basin we become even more important to service providers, in general, and to our current providers, specifically.

3. What is the regulatory environment like in Oklahoma and how does that impact (or how might it impact) your long-term development plan schedule?

   a. Oklahoma is an oil-and-gas-friendly state where decades of oil and gas operations have successfully been conducted. The regulatory environment in Oklahoma actually advantages Alta Mesa through forced pooling, which allows Alta Mesa to increase its working interest over time at Alta Mesa's planned development pace.

   b. We don't see any long-term negative impacts

4. What is your near-term targeted production growth rate? Long-term growth rate?

   a. Double-digits near-term production projected growth rate; longer-term, we intend to maintain peer-leading production growth, given the early-stage nature of our asset and development program and because of the planned acquisitions we envision executing

5. What rig count are you building towards? At what point do you see diminishing returns from additional rigs? What is the constraining factor in number of rigs you can run?

   a. Building towards 10 by yearend, 12 by yearend 2018

   b. By 2019, we will be running 13 rigs. Post-2019, our development will continue and our rig ramp will increase accordingly at a moderate pace. Alta Mesa will limit the number of rigs

we run based on our moderate leverage and adequate liquidity goals as well as our desire to enact a thoughtful development plan on our acreage position.

c. We don't see any diminishing returns by adding rigs

d. There are no real constraints to the number of rigs we can run except for possibly people; even then, it's a delay issue.

e. There is frac and water availability to worry about. Rig ramp is not the hard part, completing wells is.

6. How does KFM's growth plan integrate with (or exist independently from) Alta Mesa upstream growth plan?

    a. Over the last couple of years, it's been very similar as we've had a strong degree of collaboration

    b. At this point, the KFM plan has mirrored the AMR plan as an efficient method to process and move AMR's production and to surgically attach 3rd party production to its systems and marketing platform. Both are expected to accelerate in the new public company, as both companies expand organically and inorganically.

7. How many new employees do you think you will need to add to fully handle the assets and what you want to accomplish – are you most of the way there or half the way (or do you have what you need)? What positions have been filled and what critical positions are still vacant (and what is the plan to fill them)?

    a. Alta Mesa has the staff on hand needed to persecute the planned rig ramp and development case. Given the highly experienced nature of the Alta Mesa team, we are confident in our ability to ramp production as expected with our existing staff. Most office positions filled and field count scales with well count

    b. As a 30-year-old enterprise, we have added a substantial number of employees in key technical positions

    c. We currently have no critical positions unfilled

    d. We have most employees and contractors in place except for what may be needed for additional expansion

8. Please discuss the business plan / growth trajectory for Kingfisher Midstream? What part of the long-term plan for Kingfisher midstream is independent of Alta Mesa's acreage and development?

    a. We plan to springboard off AMR's growth for organic capex for 3rd party production, as we simultaneously pursue compelling inorganic midstream opportunities as part of maximizing KFM's skill sets, attractive currency, and strong balance sheet.

9. Which formation or area will drive most of your growth going forward? What is the rig breakdown by area in 2018 and 2019? How many wells are you going to drill in each year? **[Note: This question was deleted from Citi's document; not sure if that was by design]**

    a. Meramec/Osage/Oswego in Kingfisher County will drive most production growth in the near term; Manning is the wild card

    b. We expect Major County will contribute as more is known, wells are drilled, and infrastructure is built

    c. Most rigs will work in Kingfisher County in 2018-19 with some activity in Major County

    d. We're expecting to drill 150-250 (?) wells per year in 2018-19

10. What are the biggest risks to your business plan? How likely do you think these items are to occur and how will you address each of them?

    a. The most significant risk moving forward is ensuring we correctly and properly develop our acreage position. This will require constant focus and attention on the spacing assumptions utilized for development and being flexible to adjust our development plan approach as needed

b. Other risks are commodity prices, service costs, and ensuring market access for our production. All of these are mitigated by the nature and location of the resource and our in-house midstream expertise.

11. What drives your capital deployment decisions (NPV, IRR, etc.)? **[Note: This question was deleted from Citi's document; not sure if that was by design]**
    a. Maximizing value (NPV) and discounted NPV/Investment

    Right on. Within acceptable NPV levels, I suspect we will also worry about sustainable and prudent growth rates and maintenance of balance sheet strength
12. Is there a risk of operations related seismic activity in Alta Mesa's position (i.e. earthquakes)?
    a. Minimal. Very minimal seismic activity has occurred on Alta Mesa's acreage position and none of it is seismic response that would result in surface impacts(??)
    b. The reported earthquake concerns are many miles east and north of our position and are associated with injecting large volumes of salt water into the Arbuckle formation
    c. We have very little water production relative to other areas and most disposal in our area has been moved to the Wilcox formation from the Arbuckle
    d. We do not believe there is a meaningful risk related to seismic activity (earthquakes) concerning our acreage position → None historically in our footprint
13. What kind of operating cost and capital efficiencies do you expect in 2018 and 2019 (i.e. LOE, G&A, etc.)? What items are permanent cost improvements versus temporary?
    a. We have added SWD pipelines across the Cimarron river to mitigate high SWD trucking costs
    b. Future LOE reduction will be associated with removing gas lift compressors in favor of assisted plunger lift using small electric compressors; result is a savings of $4,800/month/well, or half of our fixed operating expense
14. How is your relationship with your joint venture partners (where you share a working interest and are not the operator)? Do those operators share a consistent vision with Alta Mesa's growth plans?
    a. We have excellent relationships with various JV partners; we have data sharing arrangements with several of them
    b. They understand our growth plans, but many are unable to keep up the capital development intensity, creating an opportunity for us to increase our working interest and net acreage position

E. Midstream & Takeaway Capacity

1. Do you see takeaway constraints in the STACK moving forward for producers generally and then for Alta Mesa specifically?
    a. We believe there will be regional takeaway constraints in some areas of the STACK, especially focused on the gas side
    b. Alta Mesa/KFM have mitigated our risk by building fit-for-purpose gathering, an expanded KFM Midstream Plant position, and securing firm transportation to non-constrained outlets
2. What is your integration strategy on water cost and infrastructure?
    a. Alta Mesa owns 100% of our SWD facilities
    b. As construction has progressed, we have laid some KFM gathering pipe within our oil, gas and water handling infrastructure right-of-way.
    c. As these assets have grown, we have considered various methods to monetize them. Now, with KFM joined to AMR, they can be considered part of the future MLP value uplift and source of cash to continue to grow the business.
3. How much processing capacity do you have today vs. gross production (requiring processing)?

a. Current capacity 60 mmcfd, with an additional 200 mmcfd under construction
b. In addition, we have 80 mmcfd in offtake capacity to other plants
c. Current gross production to KFM is 40-50 mmcfd and future growth will be well-handled by KFM

4. Do your contracts with KFM (contracted capacity) remain in place if KFM is sold to a third-party?
    a. We have first call on 100% of the 260 mmcfd capacity, and don't plan to sell KFM to a third party. It has too many operational, financial and value arbitrage advantages to AMR.
5. How do you transport your oil and are there any risks to your oil marketing operation?
    a. Some is gathered by KFM via pipe and most is trucked
    b. Longer term plan is to tie into long-haul pipe to Cushing
    c. No known risks to oil marketing operation
6. Please describe your basis exposure currently and going forward
    a. I presume the answer is that basis, particularly for natural gas, is always a short-term risk in a growing Basin. Our midstream business will be actively engaged in moving our production beyond points of constraint to eliminate basis risk and we would tend to hedge that risk where it might otherwise exist.

7. Will you always build out your own takeaway infrastructure or do you have plans for third-party services?
    a. We will remain flexible to insure our production is processed at the best possible value for our shareholders, but KFM will obviously get the first look

F. Kingfisher Midstream

1. Please explain Alta Mesa's relationship with KFM.
    a. We are one.
2. What is your plan for midstream infrastructure build-out and associated capex?
    a. Hal will allude to the organic and inorganic growth envisioned for AMR (both upstream and midstream – organic and inorganic). Mike will show capex for organic growth in his slides
3. Who are KFM's other customers? What is third-party concentration by customer?
    a. In terms of acreage dedications (323,151 gross acres)
        i. Alta Mesa – 187,311
        ii. Staghorn/Chisolm – 67,200
        iii. GST – 65,920
        iv. MRO – 640
        v. Chap – 160
        vi. CHK – 1,920

    b. In terms of volumes
        i. Current plant inlet volumes are about 55 mmcfd of which 90% is AMR
        ii. By Sep 2017, estimated available plant inlet volume is about 115 mmcfd including offtake agreements. AMR volume is 80 mmcfd and third-party volumes are about 35 mmcfd from Chisholm, GST, MRO, Chap, CHK, Red Bluff
        iii. Projected YE20 volumes are 725 mmcfd including about 425 mmcfd from AMR
4. What is the build return multiple on midstream infrastructure?
    a. ? ??

5. If Alta Mesa and third-party customers (combined) continue at the same pace of rigs, when will this combined group run out of processing capacity? Will you build more plants for them? If so, under same commercial terms? Are there any constraints to this potential expansion?
    a. This is already the case in selected areas which is why our FT on PEPL and pending processing arrangement with a major interstate is so valuable for AMR and other producers. KFM will remain alert to possibilities for debottlenecking anticipated constraints (mostly relevant to Natgas) for AMR and other third parties. The commercial terms will improve in areas where we are able to provide scarce optionality and decline in areas where we decide to compete for third party business in highly competitive areas. But, we will not sacrifice returns above cost of capital to secure competitively sourced production.
6. How does management think about potential midstream M&A opportunities?
    a. They are squarely in our sights, assuming balance sheet strength can be maintained. Our initial and ultimate currency choices will be an advantage in this arena.
7. How will the future upstream M&A involving Alta Mesa affect the current midstream strategy?
    a. Favorably in almost any plausible scenario.
8. What are the strategic goals of KFM?
    a. To act as a partner for AMR and to maximize value for AMR's shareholders through third party partnerships and an IPO of the business at the appropriate time.
9. How much volume is KFM currently flowing?
    a. About 55 mmcfd, 90% AMR
10. What is normalized maintenance capex relative to EBITDA?
    a. A new system so going to be single-digit-low on a MCX as % of EBITDA (3-5% maybe…)
11. Are any of the assets FERC regulated?
    a. None currently FERC regulated; these are gathering and processing assets not interstate
12. What pipelines and terminals do you connect with?
    a. We address this in slide deck
13. Do you expect there to be any seasonality effects on volumes and/or cash flows?
    a. Ambient conditions can always temporarily affect operations, but we do not anticipate this to be a noticeable feature of variances in year over year EBITDA growth patterns.
14. Does the company have the ability to run above nameplate capacity in the processing plants?
    a. We believe it does, existing Lincoln plant should be able to process 65-70/d based on processing model
15. What is management's philosophy with regards to funding midstream growth?
    a. Answered above and below in midstream sections
16. Will you take KFM public as a MLP? When? Why?
    a. Yes, 2019
    b. I will be prepared with schedules to show Hal, Mike, etc. on plane to East Coast
    c. The valuation uplift from KFM being taken public as an MLP is real and something that we recognize. Over the long-term, we are interesting in pursuing and MLP IPO for KFM to ensure AMR shareholders maximize their value realization from our integrated platform

G. Financial

1. What is your capex profile, cash flow outspend and what does that imply for peak leverage levels (for the upstream business, midstream business and combined business)?

   a. **AMR (using 7/21 NYMEX Strip) –** Excluding acquisitions, AMR capex ramps up from $410MM (including ~$62MM of drillco capex) in 2017 to slightly over $1B in 2020. At current NYMEX, we estimate a 2018 cash flow outspend of $343mm and become cash flow neutral in 2020. Our peak debt level occurs in mid-2020, and is $747mm, including $500mm in HY debt. Post-close, our maximum net debt/ebitdax ratio is 2.17x. After 2018, our net debt/ebitdax does not exceed 2.0x.
   b. **AMR (using Consensus Deck, avg $58/bbl and $3.09/mcf through 2020)** – Excluding acquisitions, AMR capex ramps up from $410MM (including ~$62MM of drillco capex) in 2017 to slightly over $1B in 2020. At current NYMEX, we estimate a 2018 cash flow outspend of $277mm and become cash flow positive in 2019. Our peak debt level occurs in mid-2019, and is $526mm, including $500mm in HY debt. Post-close, our maximum net debt/ebitdax ratio is 1.78x. After Q1'19, our net debt/ebitdax does not exceed 1.0x.
2. What is your capital structure philosophy and leverage throughout the cycle?
   a. Alta Mesa plans to maintain conservative credit metrics of < 1.0x leverage near team and 1.5-2.0x through the cycle; Alta Mesa hopes to preserve an optimal debt maturity profile and maintain a simplified balance sheet
3. What is the right long term capital structure - how much debt will you put on the company? Over what time frame? **[Note: This question was deleted from Citi's document; not sure if that was by design]**
   a. See 17a NOTE: See 6., below and 2. a., above. KFM will enhance AMR credit rating due to up-sizing of company and more stable perceived cash flow. Not sure debt is the right question absent a ratio. We can put on more as we grow, including with consolidation. There is no right answer on this question and it's silly other than addressing through ratios.
4. How do you think about the balance sheet vs. production growth?
   a. Production growth is one of our key objectives when NAV accretive and Alta Mesa will focus on achieving top-tier production growth, but not at the expense of over-leverage. Alta Mesa plans to maintain conservative credit metrics of < 1.0x leverage near team and 1.5-2.0x through the cycle
5. When do you anticipate going cash flow positive?
   a. 2019
6. What is your target leverage ratio and credit rating? **[Note: This question was deleted from Citi's document; not sure if that was by design]**
   a. Description
   b. Should be expressed as Debt/EBITDA not conventional leverage ratios. Mike, what will we be rated when we become public? Can we get to IG soon, if not immediately?
7. Would you lever up for an acquisition?
   a. Only to the extent that our leverage metrics remain reasonable and within our long-term leverage goal levels. Excellent.
8. What are your key debt covenants?
   a. 1-800-McCabe
9. Is your liquidity position post IPO enough to meet your 2017 and 2018 capital development plans? When do you need to raise more capital to fund your capital development plans?
   a. Yes, our capital raise from the IPO will adequately fund our development plant through 2018 and until we become cash flow positive in 2019.

H. Hedges

1. What is your hedging policy and the depth of market for hedging differentials?
   a. Continued rolling hedge strategy to protect revenues and support development program

2. What is your target percent production hedged each year? How many years out do you hedge?
    a. Expected P50 PDP production -- for up to 18 months (or less). Hal is as qualified as I to opine on this. Will be interested in his past practice and philosophy.
3. Do you hedge NGLs?
    a. We have hedged propane which is about 50% of our NGL bbl under current Ethane rejection
4. Do you hedge to NYMEX and/or basis?
    a. Typically, NYMEX; NOTE: I hope we consider basis as well, as appropriate. Doesn't KFM do this on all three products? Remember, we will be one company soon.
5. What type of hedging product do you typically utilize (swaps, collars, puts)?
    a. All – we are opportunistic in protecting our PDP production via the best priced and/or most effective structure available to us to meet our needs at that time.

I. Drilling & Completion

1. How do you choose service providers? Long term partnership or well by well decision?
    a. We have long term established relationships with most service providers; this has provided benefits as we have kept them alive during the downturn and they are slow to raise costs during the upturn
    b. We have used Latshaw Drilling and Producer's Services for stimulation; Schlumberger does most of our logging →Duel competitive suppliers
2. Any pressure on service costs?
    a. Some but, by continuing high-level operations during the downturn, we have been able to keep service costs low
    b. We also have a lot of flexibility on the proppant we use; preferring to use whatever is least expensive rather than use the most popular
    c. ½ performance gains
3. Why does Alta Mesa choose to drill one mile laterals and is there a plan to increase lateral length moving forward?
    a. One mile laterals is simply a matter of best economics for our shallower, normally pressured, naturally fractured reservoirs; we have no plans to increase lateral length moving forward. We believe it's the right decision in our acreage.
    b. One-mile laterals allow for the optimal development of Alta Mesa's acreage position and maximum type-well IRR.
        i. One-mile lateral fits into a single section; two-mile laterals require establishing a "Multi-Unit spacing"
        ii. Two-mile laterals in non-shale reservoirs are not allowed by the OCC authority in the Osage **[Note: This is no longer true; the OCC recently ruled to allow two-mile laterals in all reservoirs in OK] – good; would prefer not to have that answer any way. The technical reasons are more compelling than regulatory ones.**
        iii. Two mile laterals are typically drilled with oil based muds; in our highly fractured, normally pressured environment, fluid losses would be exorbitantly expensive
        iv. Two mile laterals require larger pipe (more steel, higher capex) to reduce friction during fracturing operations
        v. One mile laterals are less complex; reduces mechanical risk
        vi. Less proppant, fluids, and pumping time per well, more simplified design, lower friction while pumping all help to reduce costs of optimized completions

vii. Working with mineral owners across one-section (versus two-sections for longer laterals) allows for more seamless and confident development program planning

4. How would you compare your F&D cost to your peers? Why are you better or worse than your peers?
    a. Our F&D costs of $5.62/boe are among best-in-class vs peers due to lower D&C costs, lower LOE costs and (?) due to established infrastructure, and higher EUR per 1,000'
5. What "inning" would you suggest Alta Mesa is in concerning realizing operating cost and capital efficiencies (i.e. how much more room to improve do we have)?
    a. Operating and capital efficiencies are both technology and hardware driven
    b. LOE will continue to be driven down as a result of infrastructure buildout reducing trucking costs (hardware) and lower cost lifting techniques replacing gas lift compression (technology)
    c. In short, we're in the 3rd or 4th inning, but the game never ends due to continual improvement ☺ Good
6. Will you use the same D&C techniques in the newly acquired Major county acreage or will you have to alter your design?
    a. Initially, we would use the same, proven techniques and then adjust as necessary
7. As your completion evolution changes, do you expect IP rates to increase, declines to decrease or both?
    a. Historical evolution has shown both

J. Geology / Reservoir

1. Please compare your EUR/1,000' and general type curve to your peers. How does this compare to and potentially outperform historical wells? How does this compare to type curves of other peers in the basin?
    a. Our EUR/1,000' is generally higher than peers
    b. We believe this is due to 1) high degree of natural fractures in the up-dip STACK, 2) less friction (and better hydraulic rock fracturing) during the stimulation process with one-mile vs two-mile laterals
    c. Open hole completion method
2. Is there any communication between the Meramec and Osage given the extent of natural fracturing in this area?
    a. Although there is significant natural fracturing in an east-west sense, we don't believe we see many natural fractures that traverse the entire +500' thick Meramec/Osage section
3. What is a good porosity cut-off for the Oswego formation?
    a. Due to low porosities in nearly all resource plays, we don't believe porosity cutoffs make sense as they might in a conventional play
    b. Instead, the focus in on maximizing stimulated rock volume (SRV)
4. What are the recent results on your full section development density tests?
    a. What are the recent results on your full section development density tests?
        i. We don't currently have any full section density tests
        ii. In general, both the single wells and density tests we have drilled are performing closely to what would be predicted using volumetrics
    b. How were the parent wells effected during the completions?
        i. In general, parent wells were either unaffected or improved in production rate
    c. How do the child wells perform compared to the original parent wells?

i. In one instance, where parent wells were not pressurized prior to frac, the child wells did not perform as well

ii. In one instance, where parent wells were pressurized, the child wells performed as expected

d. How many more tests do you feel like you need to do to feel completely confident for the go forward development plan?

i. Each section/township will have a custom design

ii. We are confident in a go-forward development plan in several areas

iii. Some areas need further testing

e. When do you feel the right time is to test your downspacing options (660' inter-well spacing)

i. We have one test in that regard

ii. Further testing is warranted

5. If you could rank your "additional formations", which zones are you the most excited about and could become reserves in the near future?

a. Not sure how much we should share, but currently economic type curves are associated with Meramec/Osage, Oswego, Manning, Hunton, Cherokee Shale (contains Prue, Skinner and Redfork sands)

b. In order rank (from $63/bbl to $72/bbl breakeven) – Big Lime, Chester Shale, Woodford Shale

c. Note: All formations have produced vertically with the exception of the Chester Shale

K. Other

1. Do you have the organization in place to deliver expedited rig ramp? What are organizational expectations / plans to execute? **[Note: This question was deleted from Citi's document; not sure if that was by design]**

a. We have a significant organization that is experienced and has worked together at Alta Mesa for many years

b. We can readily ramp up rigs with the current organization and add future employees to meet our existing plan for capex. We have been throttling the organization back for 3 years because of capital constraints

2. Please describe key management previous experience. What is the biggest organization you have run or been a part of?

a. Extensive and substantial experience from Jim Hackett (Anadarko Chief Executive, Devon COO, Ocean Energy CEO) and Hal Chappelle (Alta Mesa CEO) managing thousands of employees. Team is positioned well to persecute long-term development of the STACK play; See bio's in presentation

3. What is your long-term plan for KFM? Will you leave the midstream operations integrated with the upstream in a C-Corp or is there a plan to MLP IPO KFM and when will that occur?

a. Our current plan is to consider an IPO of a midstream MLP in 2019 and to install a generous IDR structure into a GP that will then be taken public.

4. In the internal competition for capital expenditure dollars within Alta Mesa, how does Alta Mesa upstream rank / compete versus KFM? Whose base capital budget takes priority?

a. Beyond supporting flow assurance and favorable pricing for Alta Mesa, KFM's growth plans will depend on available capital. We hope and plan on growing both entities together and, when appropriate, separately in order to maximize shareholder wealth.

<u>**Other Information via Citi**</u>

With regard to Blaine County NW STACK / STACK transition:

1- Geologically it is a transition area from STACK Meramec to NW STACK Upper Meramec
2- Osage has been proven in the Northern part and high ROR Meramec wells in the center of Blaine (to the east)
3- In the South Western section, huge Woodford and Meramec dry gas wells
4- 5K lateral has been the norm except Continental and Cimarex is also drilling 10K. CHK also moves to 2-mile laterals in Meramec in 2017

Operator Updates

Continental:
- Southern Blaine/Custer boundary: Continental is very active drilling Upper Meramec and Woodford wells (~10,000 ft laterals).
  - o Upper Meramec wells are mostly dry gas (Anderson Half, Edith Mae, Eichelberger with 2600-3200 boepd IP)
  - o Woodford wells are in dry gas window as well (Slagell and Lacretia wells with 2000 – 2600 boepd IP)
- Blaine/Dewey county boundary: drilling dry gas Woodford wells (~2,000 boepd with 10-15% liquid)
- To the center of Blaine, Continental is targeting Meramec which has the highest RORs compared to Dewey/Major Meramec wells
- They have total of 12 rigs (7 Meramec, 5 Woodford) 2 of them in Custer and 3 in Blaine

Newfield:
- Testing increased proppant/fluid completions in Blaine and doing extensional leasing North of Blaine in Major.

Cimarex:
- Downspaced to 8 wells in the center of Blaine (Peterson pad)
- Testing longer laterals (10,000 ft) in Blaine (~8 wells) and comparing with 5,000 ft lateral performance

Devon
- Active in the Easter side of Blaine drilling Meramec wells (called Showboat project area)

Carrera
- Targeting Upper Meramec and Osage in the Northern Blaine: good wells in the area defining Meramec and Osage boundaries
  - o Upper Meramec wells: Butterfinger, Heath with ~550 boepd IP with ~20% oil
  - o Lower Osage wells: Twix and Robison Payday with 650-850 boepd IP with ~45%oil
- Encap backed considering marketing late this year
- Drilled ~15 wells in Major, Dewey and Blaine

Council Oak
- Drilled 5 wells which some are in the Northern Blaine: low IP wells
- Encap backed considering marketing late this year
- Drilled ~15 wells in Major, Dewey and Blaine

Chesapeake

- Northern Blaine/Major boundary: Drilling Upper Meramec wells and shifting to 2-mile laterals
  - o Earlier wells such as Hoskins in the Northern Blaine with ~1000 boepd with ~60 % oil
- Encap backed considering marketing late this year
- Drilled ~15 wells in Major, Dewey and Blaine

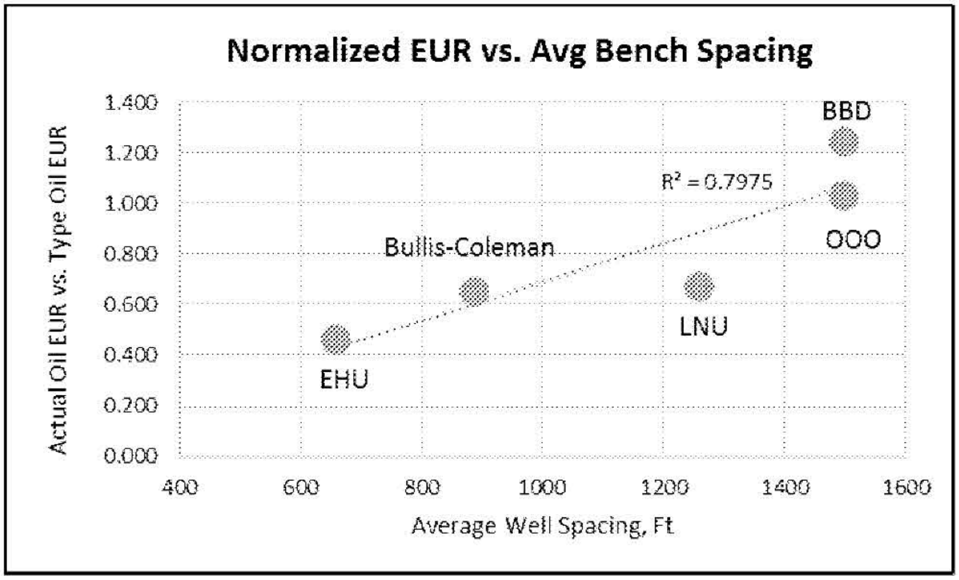
Spacing Tests and Parent-Child Tests

1. Now that many units are held by an initial "parent" well, how do you think about pattern infill or "child" wells? Other operators (NFX/CLR) seem to have child well results that are underperforming the type curve.
   a. Our parent-child tests have been very informative
   b. There are many factors affecting child well performance including 1) oil in place, 2) well spacing, 3) frac size, 4) pressure sink created by parent well, 5) Gas production in the parent well, and 6) where the well is landed in the section
   c. We believe the most important factors determining child well performance are 1) well spacing and 2) pressuring up the parent wells prior to frac ops on the child wells; we have demonstrative evidence that these two factors are critical and we can control them.

Spacing Tests and Parent-Child Tests - Analysis

2. Now that many units are held by an initial "parent" well, how do you think about pattern infill or "child" wells? Other operators (NFX/CLR) seem to have child well results that are underperforming the type curve.
   a. In the analysis of these situations, there are a lot of moving parts
      i. Recoverable oil in place (if you have 1 MMBO recoverable in a particular section, you will have poorer results per well with 10 wells vs 4)
      ii. How long have the parent wells produced (lower pressure creates pressure "sink" and impacts child fracs)?
      iii. How much gas produced (depletion drive, so oil is the drive mechanism)?
      iv. Number and size of frac stages in parent and child wells (interference)
      v. Spacing of wells (interference)
      vi. Where is the well landed in the +500' section (lower benefits from gravity drainage)?

b. AMR's spacing tests have and parent-child tests have performed consistently depending on spacing between wells in each bench



c. When comparing normalize EUR (Total Pattern EUR)/(Type Well EUR * Wellcount) vs well spacing, there is a very good correlation (R^2 = 0.8)

d. Our parent-child patterns are the LNU 5 well pattern and the Bullis-Coleman 10 well pattern
   i. LNU Pattern
      1. Parent LNU wells were initially drilled 2,640' apart in the lower Osage; 3 child wells were drilled about 1 year later. One child was drilled in the lower Osage between the parents, the other two were drilled in the upper Osage about 1,200' apart. Average well spacing is about 1,260'
      2. Parent wells were not pressured prior to drilling/fracs on child wells; we believe this factor contributes to this pattern being off trend
      3. It appears the interior fracs improved the parent wells as they are substantially better than the child wells
   ii. Bullis-Coleman Pattern
      1. Parent wells were drilled 4,000' apart. The parent Bullis well was the second horizontal well drilled in 2012, the parent Coleman well was drilled in late 2015. The eight infill wells were drilled in 2016 and put on production in 2017. The average well spacing is about 900'.
      2. Parent wells <u>were</u> pressured prior to drilling/fracs on child wells (100 MBW injected into each); we believe this factor contributes to this pattern staying on trend
      3. It appears the interior fracs improved the parent wells; the original Bullis well actually increased from 10 bopd to 200 bopd.

e. Based on the above, we believe we can realize our type curve using 1,500' spacing; thus, we have built our development patterns 3 benches with 1,500' spacing

f. The "economic optimum" may more or less wells depending on commodity prices and the "custom design" for each section based on volumetrics

3. Other operators may be experiencing issues due to a number of factors
    a. Well spacing
    b. Pressuring or not pressuring parents
    c. Frac size
        i. NFX completions manager (friend of mine) stated they upsized their frac sizes on single wells and then pumped the same formula on child wells without thinking about the impact
    d. Fluid makeup
        i. CLR has a high gas content; gas is much more mobile than oil and it is likely they will need to space their wells much farther apart than 1,500'